[Continued on next page]

(54) Title: APPARATUS AND METHODS RELATING TO DOWNHOLE OPERATIONS

(57) Abstract: A communication system for use in a wellbore, a downhole tool, and a method includes a transmitter coupled to a wireline, and a receiver located remotely from the transmitter. The wireline is capable of acting as an antenna for the transmitter. The wireline is a slickline, and the transmitter may be associated with, provided on, or an integral part of a downhole tool or tool string. The transmitter typically transmits data collected or generated by the downhole tool or the like to the receiver, which is preferably located at, or near, the surface of the wellbore. The wireline is typically provided with an insulating coating. Also, a distance measurement apparatus and a method for measuring the distance travelled by a wireline includes at least one sensor coupled to the wireline, and the sensor is capable of sensing known locations in a wellbore.

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1   "Apparatus and Methods Relating to Downhole

2   Operations"

3

4   The present invention relates to apparatus and

5   methods relating to downhole operations, and

6   particularly, but not exclusively, to wireline

7   operations.

8

9   Wireline is a term commonly used for the operation of

10   deploying and/or retrieving tools or the like using a

11   wire, the wire being one of several different types

12   of construction. For example, slicklines are wires

13   which comprise a single strand steel or alloy piano-

14   type wire which currently have a diameter of around

15   0.092 inches to 0.125 inches (approximately 2.34mm to

16   3.17mm) in use, with the possibility of increasing

17   this to 0.25 inches (approximately 6.25mm) in the

18   future.

19

1 Wirelines may also be of a braided construction which
2 can also carry single or multiple electrical
3 conductor wires through its core and is typically of
4 a diameter in the order of 3/16 of an inch
5 (approximately 4.76mm) or above. Slick tubing, more
6 commonly known as coiled tubing, is in the form of a
7 continuous hollow-cored steel or alloy tubing which
8 is usually of a diameter greater than the preceding
9 types of wireline.

10
11 Wirelines are conventionally used to insert and/or
12 retrieve downhole tools from a wellbore or the like.
13 The downhole tools are typically deployed to perform
14 various downhole functions and operations such as the
15 deployment and setting of plugs in order to isolate a
16 section of the wellbore. It is advantageous and
17 often essential to know the distance of travel of the
18 wireline so that the location of the tool within the
19 wellbore is known.

20
21 Wirelines are conventionally stored on a winching
22 unit typically located at the surface in the
23 proximity of the top of a borehole. It should be
24 noted that "surface" in this context is to be
25 understood as being either atmospheric above ground
26 or sea level, or aquatic above the seabed. Although
27 the methods and apparatus employed in wireline
28 operations vary in detail, the wireline is commonly
29 introduced into the wellbore (the wellbore
30 conventionally being cased, as is known) via a series
31 of sheaves or guide rollers. The sheaves or guide

1 rollers facilitate, in the first instance, a
2 substantially vertical orientation of the wireline.
3 The wireline passes through a substantially
4 vertically-orientated superstructure tube having an
5 internal open-ended bore, the tube being positioned
6 on top of a wellhead. Thus, any downhole tool can be
7 introduced into the wellbore.
8
9 The wireline is coupled at its distal (downhole) end
10 to the downhole tool, typically via a part of the
11 tool known as a rope-socket. The rope-socket is
12 conventionally used to provide a mechanical
13 connection between the wireline and the downhole tool
14 (or a string of downhole tools known as a tool
15 string).
16
17 The conventional method of measuring the downhole
18 tool depth is to run the wireline against a measuring
19 wheel which is a pulley wheel of known diameter. It
20 should be noted that use of "depth" in this context
21 is to be understood as being the trajectory length of
22 the downhole tool, which may be different from
23 conventional depth if the wellbore is deviated, for
24 example. In order to calculate the distance of
25 travel of the wireline, a number of variable factors
26 must be known. It is a prerequisite that the
27 rotational direction of the pulley wheel, the number
28 of revolutions thereof, the diameter of the pulley
29 wheel and, depending upon the type of pulley wheel
30 (that is, whether a point-type contact or arc for
31 example), the diameter of the wireline, must all be

1   known before the distance of travel of the wireline

2   within the wellbore can be calculated.

3

4   However, with this conventional method for

5   calculating the distance of travel of the wireline, a

6   number of factors can render the calculation

7   inaccurate. The occurrence of wheel slippage, the

8   stretch of the wireline (due to the weight of the

9   wireline itself, and/or the weight of the tool string

10   which is attached thereto), the effect of friction

11   and the well-contained fluid buoyancy all contribute

12   to decrease the accuracy of the tool depth

13   measurement.

14

15   In order to improve the accuracy of this conventional

16   depth measurement, it is known to combine the

17   measured tensile load, the known stretch co-efficient

18   of the wireline, and the conventionally measured tool

19   depth as described above, to recalculate the tool

20   depth measurement on a continuous basis (ie in real

21   time) using a processing means, such as a computer or

22   the like.

23

24   However, the accuracy of the aforementioned depth

25   measurement correction method relies on an

26   experimentally determined constant (ie the stretch

27   co-efficient of the wireline) and the surface

28   measurements on the wireline. The resulting

29   correction does not include the significant combined

30   effect that well fluid temperature, tool buoyancy and

1 well geometry have on the accuracy of the depth
2 correction.
3
4 According to a first aspect of the present invention
5 there is provided distance measurement apparatus for
6 measuring the distance travelled by a wireline, the
7 apparatus comprising at least one sensor coupled to
8 the wireline wherein the sensor is capable of sensing
9 known locations in a wellbore.
10
11 The wireline is typically a slickline.
12
13 According to a second aspect of the present invention
14 there is provided a method of measuring the distance
15 travelled by a wireline, the method comprising the
16 steps of coupling at least one sensor to the
17 wireline, the at least one sensor being capable of
18 sensing known locations in a wellbore; running the
19 wireline into the wellbore; calculating the depth of
20 the at least one sensor using any conventional means;
21 generating a signal when the at least one sensor
22 passes said known locations; using the signal to
23 calculate a depth correction factor; and correcting
24 the calculated depth using the depth correction
25 factor.
26
27 Preferably, the apparatus includes transmission means
28 for transmitting data collected by the at least one
29 sensor to a receiver located remotely from the
30 apparatus. Preferably, the wireline is capable of
31 acting as an antenna for the transmission means.

The sensor may be coupled to the wireline at any point thereon, or may form an integral part thereof. The sensor is preferably coupled at or near a downhole tool whereby the distance travelled by the tool (and thus its location within the wellbore) can be calculated. Alternatively, the sensor may form part of a downhole tool or the like.

The sensor typically comprises a magnetic field sensor, and preferably an array of magnetic field sensors. The array of magnetic field sensors are typically provided on a common horizontal plane. Alternatively, the sensor may comprise a radio frequency (RF) sensor, and preferably an array thereof. Where an RF sensor is used, the wellbore is typically provided with RF tags at known locations.

The wireline is preferably electrically insulated. The wireline may be sheathed to facilitate electrical insulation. Alternatively, the wireline may be passed through a stuffing box or the like to facilitate electrical insulation and/or isolation.

According to a third aspect of the present invention there is provided a downhole tool comprising coupling means to allow the tool to be attached to a wireline, at least one sensor capable of detecting known locations in a wellbore and generating a signal indicative thereof, and a transmission means capable of transmitting the signal.

1

2   There is also provided a method of tracking a member

3   in a wellbore, the method comprising providing a

4   sensor on the member, inserting the member and sensor

5   into the wellbore, obtaining information indicating

6   the position of the sensor in the wellbore, and

7   determining the distance travelled by said member

8   from said sensor information.

9

10   The wireline is preferably used as an antenna for the

11   transmission means.

12

13   The coupling means typically comprises a rope-socket.

14   The rope-socket is preferably provided with signal

15   coupling means to couple the signal generated by the

16   transmission means to the wireline.

17

18   The sensor typically comprises a magnetic field

19   sensor, and preferably an array of magnetic field

20   sensors. The array of magnetic field sensors are

21   typically provided on a common horizontal plane.

22   Alternatively, the sensor may comprise a radio

23   frequency (RF) sensor, and preferably an array

24   thereof. The array of RF sensors are typically

25   provided on a common horizontal plane.

26

27   The downhole tool is preferably powered by a DC power

28   supply, and most preferably a local DC power supply.

29   The DC power supply typically comprises at least one

30   battery.

31

1   According to a fourth aspect of the present invention
2   there is provided a wireline wherein the wireline is
3   provided with an insulating coating.

4
5   The insulating coating is typically an outer coating
6   of the wireline. The wireline typically comprises a
7   slickline.

8
9   The insulating coating typically comprises at least
10   one enamel material. The enamel material typically
11   consists of one or more layers of coating whereby
12   each individual layer adds to the overall required
13   coating properties. Additionally, each layer of
14   enamel material preferably has the required bonding,
15   flexibility and stretch characteristics at least
16   equal to those of the wireline.

17
18   The enamel material can typically be applied to the
19   wireline by firstly applying a thin layer of
20   adhesive, such as nylon or other suitable primer.
21   Thereafter, one or more layers of an enamel material
22   such as polyester, polyamide, polyamide-imide,
23   polycarbonates, polysulfones, polyester imides,
24   polyether, ether ketone, polyurethane, nylon, epoxy,
25   equilibrating resin, or alkyd resin or theic
26   polyester, or a combination thereof, are preferably
27   applied. The enamel material is preferably
28   polyamide-imide.

29
30   According to a fifth aspect of the present invention
31   there is provided a communication system for use in a

wellbore, the system comprising a transmitter coupled
to a wireline, and a receiver located remotely from
the transmitter, wherein the wireline is capable of
acting as an antenna for the transmitter.

The wireline is typically a slickline.

The transmitter is typically associated with,
provided on, or an integral part of a downhole tool
or tool string, whereby the downhole tool or tool
string is typically suspended by the wireline.

The transmitter typically facilitates the
transmission of data collected by the downhole tool
or the like to the receiver. The transmission means
typically comprises a transmitter. The receiver is
typically located at, or near, the surface.

Optionally, the communication system is arranged
whereby it can facilitate two-way communication
between the downhole tool and the receiver. In this
embodiment, a transmitter and a receiver are
typically located downhole. Additionally, a
transmitter and a receiver are also located at, or
near, the surface. The transmitter and receiver at
the surface and/or downhole may be replaced by a
transceiver located downhole and at, or near, the
surface.

The transmitter may be coupled to the wireline at any
point thereon, or may form a part thereof. The

1   transmitter is typically coupled at or near a
2   downhole tool whereby the distance travelled by the
3   tool, the status of the tool or other parameters of
4   the tool, can be transmitted to the receiver.
5   Alternatively, the transmitter may form an integral
6   part of a downhole tool.

7
8   The wireline is preferably electrically insulated.
9   The wireline may be sheathed to facilitate electrical
10   insulation. Alternatively, the wireline may be
11   passed through a stuffing box or the like to
12   facilitate electrical insulation and/or isolation.

13
14   According to a sixth aspect of the present invention
15   there is provided apparatus for indicating the
16   configuration of a downhole tool or tool string, the
17   apparatus comprising at least one sensor capable of
18   sensing a change in the configuration of the downhole
19   tool or tool string and generating a signal
20   indicative thereof, and a transmission means
21   electrically coupled to the at least one sensor for
22   transmitting the signal to a receiver.

23
24   The downhole tool is preferably suspended in a
25   borehole using a wireline, and the wireline is
26   preferably capable of acting as an antenna for the
27   transmission means.

28
29   The transmitter typically facilitates the
30   transmission of data collected by the sensor to the
31   receiver. The transmission means typically comprises

1   a transmitter. The receiver is typically located at,
2   or near, the surface.
3
4   Optionally, the communication system is arranged
5   whereby it can facilitate two-way communication
6   between the downhole tool and the receiver. In this
7   embodiment, a transmitter and a receiver are
8   typically located downhole. Additionally, a
9   transmitter and a receiver are also located at, or
10 near, the surface. The transmitter and receiver at
11 the surface and/or downhole may be replaced by a
12 transceiver located downhole and at, or near, the
13 surface.
14
15 The sensor typically comprises an electric or
16 magnetic sensor which is coupled to the downhole tool
17 wherein a discontinuity of the electric or magnetic
18 connection triggers a signal, or a plurality of
19 signals. These signals can then be transmitted to
20 the surface to indicate the status of the tool. In
21 one embodiment, the sensor may be coupled between a
22 tool string and a downhole tool which is to be
23 deployed into a wellbore, wherein discontinuity of
24 the electric or magnetic connection indicates that
25 the tool has been deployed. Alternatively, the
26 sensor may be coupled to a distal end of the tool
27 string, and the downhole tool which is to be
28 retrieved from a wellbore, is provided with a similar
29 sensor, wherein continuity of the electric or
30 magnetic connection indicates that the tool has been
31 retrieved.

1

2   The sensor may also be coupled to part of a downhole

3   tool which changes status during operation of the

4   tool (ie a valve, sleeve or the like) wherein the

5   sensor indicates the status of the part of the

6   downhole tool by a change in continuity.

7

8   The sensor may comprise a proximity sensor, magnetic

9   sensor or the like.

10

11   The wireline is preferably electrically insulated.

12   The wireline may be sheathed to facilitate electrical

13   insulation. Alternatively, the wireline may be

14   passed through a stuffing box or the like to

15   facilitate electrical insulation and/or isolation.

16

17   Embodiments of the present invention shall now be

18   described, by way of example only, with reference to

19   the accompanying drawings in which:

20   Fig. 1 is a part cross-section of a downhole

21   tool according to a third aspect of the present

22   invention;

23   Fig. 2 is a schematic diagram of a typical

24   wireline apparatus;

25   Fig. 3 is an enlarged view of part of the

26   wireline apparatus of Fig. 2;

27   Fig. 4 is a schematic diagram of a transmitter

28   which forms part of an electronic system for use

29   with the downhole tool of Fig. 1; and

30   Fig. 5 is a schematic diagram of a receiver

31   which forms part of an electronic system located

1   at the surface for receiving signals from the

2   downhole tool of Fig. 1.

3

4   Referring to the drawings, Fig. 1 shows an embodiment

5   of part of a distance measuring apparatus, generally

6   designated 10. The apparatus 10 includes a slickline

7   12. Although reference will be made herein to use of

8   a slickline, it will be appreciated that other types

9   of wireline may be used, such as a braided line or

10   cable, coiled tubing or the like. Slickline 12 is

11   typically stored on a reel 14 which forms part of a

12   winching device 16 (Fig. 2), commonly known in the

13   art as a wireline winch unit. The winching device 16

14   is typically located at the surface. It should be

15   noted that "surface" in this context is to be

16   understood as being either atmospheric above ground

17   or sea level, or aquatic above a seabed.

18

19   The slickline 12 is introduced into a cased wellbore

20   (not shown) via a plurality of sheaves or guide

21   rollers, as illustrated in Fig. 2. The sheaves or

22   guide rollers divert the slickline 12 into a

23   substantially vertical orientation. The slickline 12

24   passes through a vertically-orientated superstructure

25   tube 18 which has an internal open-ended bore, the

26   tube 18 being positioned above a wellhead, generally

27   designated 20.

28

29   Referring to Fig. 3, there is shown in more detail a

30   part of the slickline apparatus of Fig. 2. Located

31   at an upper end of the tube 18 is a sheave wheel 22

1   which guides the slickline 12 from a substantially

2   upward direction through 180° to a substantially

3   downward direction. The slickline 12 then passes

4   through a stuffing box, generally designated 24 in

5   Fig. 3, which typically includes an internal blow-out

6   preventer (BOP) 26.

7

8   The slickline 12 enters the tube 18 and continues

9   downward therethrough and into a main BOP 28 and the

10 wellhead 20.

11

12 The slickline 12 is coupled at a lower end thereof to

13 a part of a downhole tool commonly known as a rope-

14 socket 30 (Fig. 1). The main function of a rope-

15 socket 30 is to provide a mechanical linkage between

16 the slickline 12 and the tool or tool string. The

17 mechanical linkage may be any one of a plurality of

18 different forms, but is typically a self-tightening

19 means. In the embodiment shown in Fig. 1, the rope-

20 socket 30 includes a wedge or wire retaining cone 34

21 which engages in a correspondingly tapered retaining

22 sleeve 36.

23

24 The rope-socket 30 is also provided with a sealing

25 means which seals around the slickline 12 to provide

26 a seal between the rope-socket 30 and the well

27 environment around the slickline 12. The sealing

28 means typically comprises a seal or gasket 44 which

29 isolates and insulates the interior of the rope-

30 socket 30 from the well environment.

31

In the embodiment shown in Fig. 1, the rope-socket 30
also provides an electrical coupling between the
slickline 12 which is capable of acting as a
transmitter/receiver radio frequency (RF) antenna and
a downhole tool 32. The tool 32 typically comprises
an upper sub 38 which is coupled (typically by
threaded connection) to an intermediate sub 40, which
is in turn coupled (typically by threaded connection)
to a lower sub 42.

The upper sub 38 is provided with a screw thread 38t,
typically in the form of a pin, which engages with a
corresponding internal screw thread 30t, typically in
the form of a box, on the rope-socket 30. These
(threaded) connections 30t, 38t allow the rope-socket
30 and tool 32 to be (mechanically) coupled together.

Additionally, the rope-socket 30 is provided with
coupling means which electrically couples a metal or
otherwise electrically conductive portion of the
slickline 12 and a transmitter 46 (a transceiver
typically being used to facilitate two-way
communication) of the tool 32. The coupling means
typically comprises an electrical terminal 48 which
is electrically isolated from the body of the rope-
socket 30 using an insulating sleeve 50.

The upper sub 38 of the tool 32 is provided with an
electrical pin or contact plunger 52 which engages
with the electrical terminal 48 within the rope-
socket 30. The contact plunger 52 is typically

1 spring-loaded using spring 54 so that it can move
2 longitudinally (with respect to a longitudinal axis
3 of the tool 32) to facilitate coupling of the rope-
4 socket 30 and the tool 32. A lower end of the
5 plunger 52 is in contact with a main contactor 56
6 which is electrically coupled to the transmitter 46.
7 This facilitates coupling of signals generated by the
8 transmitter 46 through the plunger 52 and the
9 terminal 48 to the slickline 12, the slickline 12
10 acting as an antenna for transmitting and/or
11 receiving signals, as will be described.

12
13 The tool 32 is also provided with an array of field
14 sensors 58 which are used to detect differences in
15 the magnetic flux at the junctions of, or collars
16 between, successive casing sections which are used to
17 case the wellbore, whereby the location of the tool
18 32 within the wellbore can be calculated, as will be
19 described.

20
21 The tool 32 is preferably powered by a (local) direct
22 current (DC) power source, typically comprising one
23 or more batteries 60. The batteries 60 provide a
24 local electrical power supply for the tool 32.
25 Conventionally, downhole tools are powered using a
26 central conductor of a braided line to transmit
27 electrical power to the tool from the surface.
28 However, there are substantial losses using this
29 method, particularly where the tool is located some
30 distance down the wellbore. In addition, the central
31 conductor of the braided line is typically relatively

1 small in diameter and thus high voltage drops can be

2 induced. Use of a local power supply (ie the

3 batteries 60) obviates the need for an electrical

4 power connection to the surface.

5

6 The tool 32 may include a pressure sensor 62 which is

7 electrically coupled to the transmitter 46 and when

8 present can be used to measure the pressure external

9 to the tool 32.

10

11 Referring now to Fig. 4, there is shown a schematic

12 diagram of a transmitter 46 which forms a part of an

13 electronic system located within the tool 32. The

14 batteries 60 provide electrical power to the system

15 in general. On detection of a positive over-pressure

16 to atmospheric level, that is after introducing the

17 tool 32 into the tube 18 (Fig. 2) and opening of the

18 wellhead 20 to allow well pressure to equalise in the

19 tube 18, the pressure sensor 62 activates the

20 magnetic field sensors 58.

21

22 The magnetic field sensors 58 may be of the type

23 described in German Patent Application Number DE-A1-

24 19711781.3 (Pepperl + Fuchs GmbH), for example, and

25 are typically mounted within a section of the tool 32

26 which is at least partially manufactured from a

27 conventional non-ferrous material. This ensures high

28 sensitivity when detecting casing or collar joints.

29

30 German Patent Application Number DE-A1-19711781.3

31 describes use of the sensors 58 in conjunction with a

1   remnance inducing magnet ring. The wellbore casing

2   sections described therein exhibit a weak magnetic

3   remnance due to the influence of the earth's magnetic

4   field, the difference in the magnetic flux and/or the

5   history of previous well service operations. If the

6   difference in the magnetic flux at the junctions

7   between the wellbore casing sections is

8   insufficiently weak or disorientated, it is

9   advantageous to re-magnetise the casing sections by

10 either running in a separate downhole tool provided

11 with one or more axially orientated magnets prior to

12 commencing the tool detection, or to incorporate one

13 or more such magnets into the tool 32, or the tool

14 string of which the tool 32 forms part.

15

16 The plurality of sensors 58 are orientated to

17 preferentially sense the locality and proximity of a

18 collar or casing joint which the tool 32 passes, by

19 detecting the variation or switch in magnetic flux at

20 the junctions or collars between successive casing

21 sections. It is preferred, but not essential, to

22 have the sensors 58 disposed on a common horizontal

23 plane within the tool 32. The latter, in combination

24 with the series connection of the sensors 58 maximise

25 the positive sensing of the collars or casing joints

26 as the tool 32 passes.

27

28 When a casing collar or joint is detected, power is

29 supplied to the transmitter 46. The transmitter 46

30 is located within the tool 32 and is electrically

31 coupled to the batteries 60, the pressure sensor 62

1   and the magnetic field sensors 58 via suitable

2   electrical connections within the tool 32.

3   Alternatively, the transmitter 46 may be coupled

4   thereto via a system of insulated downhole tool

5   components which provide electrical connections

6   isolated from the well environment, the electrical

7   connections being suitable connectors between the

8   separate downhole sections which make up the complete

9   downhole tool string.

10

11   The transmitter 46 may be of a type supplied by RS

12   Components under catalogue number RS 740-449, which

13   is designed to operate in conjunction with a 418 MHz

14   FM transmitter module also supplied by RS Components

15   under catalogue number RS 740-297. However, it

16   should be noted that the transmitter specified above

17   is only an example of one possible transmitter, and

18   that there are many other possible transmitters and

19   frequencies which could be utilised in it's place.

20   The components identified above should be tested for

21   conformity to the particular operational requirements

22   and criteria and for operation in wellbore

23   environments.

24

25   The transmitter 46 typically has the facility for

26   address coding (using DIL switch settings 66 in Fig.

27   4), and data bit settings using either a DIL switch

28   68 (Fig. 4) or driven by external switches, relay

29   transistors or CMOS logic via an auxiliary connector,

30   designated 70 in Fig. 4). DIL switch 68 is used to

31   switch data channels (ie the four data channels

1 relating to each one of the sensors 58) on and off,
2 typically using opto-electronic switches 69. Thus,
3 the signal from any one, some or all of the sensors
4 58 can be set to be transmitted. The output from the
5 DIL switch 66 is typically processed by an encoder
6 convertor 67 which encodes the address coding (as set
7 by the DIL switch 66) into the transmission. RF
8 transmission can be initiated by external contact
9 closure and the provided link on the auxiliary
10 connector 70 (eg, coupling TXEN to ground).
11
12 It will be appreciated that with the above described
13 transmission method, the transmitter 46 is not
14 permanently activated and allows only a single
15 transmission upon external contact closure. The
16 duration of the transmission may be altered by
17 changing the values of RT, CT and/or RT2 and CT2
18 respectively, but is typically in the order of 1
19 second duration (set by default). The period of
20 transmission may be determined as follows :-
21 2.2*RT*CT (which changes the interval between
22 transmission in seconds) and 0.7*RT2*CT2 (which
23 changes the duration of the transmissions in
24 seconds).
25
26 The transmitter 46 ground connection (ie from any
27 point on the ground connection 64) and RFout
28 connection 65 are electrically coupled to the rope-
29 socket 30 using, for example, electrical connections
30 within the tool 32 (or otherwise as described above)
31 and the plunger 52 and electrical terminal 48

1   provided on the tool 32 and rope-socket 30

2   respectively (Fig. 1). These connections are shown

3   schematically in Fig. 4, with the RFout connection 65

4   being coupled to the slickline 12 which acts as an

5   antenna.

6

7   As previously noted, the slickline 12 acts as an

8   antenna for this RF transmission and thus the

9   slickline antenna 12 carries and guides the

10   transmission towards the surface. The RF

11   transmission (ie the electromagnetic (modulated)

12   wave) contains encoded data which is radiated into

13   free-space or any other antenna surrounding medium at

14   or near the tube 18, for example. The precise

15   location of where the RF transmission is radiated

16   into free-space is not important, but it is typically

17   at some point at the surface where the RF

18   transmission can be radiated over a larger area.

19

20   Located within the radiation range of the transmitter

21   antenna (ie the slickline 12), for example located at

22   the surface or within the tube 18, is a receiver 80,

23   shown in Fig. 5. Fig. 5 is a schematic diagram of

24   the receiver 80 which forms a part of an electronic

25   system located at or near the surface. The receiver

26   80 may be, for example, of the type supplied by RS

27   Components under catalogue number RS 740-455, which

28   is designed to operate in conjunction with a 418 MHz

29   FM receiver module 84 supplied by RS Components under

30   catalogue number RS 740-304. However, it should be

31   noted that the receiver specified above is only an

1   example of one possible receiver, and that there are

2   many other possible receivers which could be utilised

3   in it's place. It should also be noted that the

4   receiver 80 should be matched to the frequency of the

5   transmitter 46. The components identified above

6   should be tested for conformity to the particular

7   operational requirements and criteria and for

8   operation in wellbore environments.

9

10   The receiver 80 typically has the facility for

11   address coding (using suitable DIL switch settings on

12   switch 82) to match and pair with the address code of

13   the transmitter 46. The settings of the receiver

14   board jumpers JP1 and JP2 determine the output

15   configuration of the transmission from the tool 32.

16   Jumper JP2 is used to select whether the output is

17   high or low (ie the logic level) which selects

18   whether the output on the four channels out 0 to out

19   3 on an auxiliary connector 88) are either a logic

20   high or a logic low. Jumper JP1 is used to select

21   whether the output on the channels out 0 to out 3 are

22   latched (ie permanently high or low) or intermittent.

23

24   The receiver module 84 receives the signal from the

25   antenna 12 at an RFin connection 86. The signal is

26   then processed in the FM receiver module 84 and

27   output to a decoder 90. The decoder 90 decodes the

28   address coding from the transmission and thus the

29   receiver 80 is only activated when the address of the

30   transmitter 46 matches the address settings of the

31   DIL switch 82 (ie the address of the receiver 80).

1   The output from the decoder 90 is then fed to a data
2   selector 92 which automatically activates one, some
3   or all of the output channels out 0 to out 3,
4   depending upon which of the four channels have been
5   activated by the settings of the DIL switch 68 on the
6   transmitter 46. The output of the selector 92 is
7   then fed to a seven stage darlington driver 94 which
8   is used to drive the outputs on the auxiliary
9   connector 88. The outputs of the auxiliary connector
10 88, in particular the outputs out 0 to out 3 are
11 typically coupled to a visual indicator (ie a light
12 emitting diode (LED)) which can be used to allow a
13 user to determine which of the sensors 58 detected a
14 collar or casing joint. Alternatively, or
15 additionally, the outputs of the auxiliary connector
16 88 may be coupled to a processing means (eg a
17 computer) located at or near the surface for further
18 processing of the data.
19
20 It should be noted that although the transmitter 46
21 is shown coupled to four sensors 58 (Fig. 4) and thus
22 has four channels, the transmitter 46 may be provided
23 with more or less than four channels, depending upon
24 the number and grouping of sensors 58 within tool 32.
25
26 In use, the tool 32 is attached to the slickline 12
27 as described above and introduced into a cased
28 wellbore in a conventional manner. The casing can be
29 of any type, that is, for example, either
30 electrically conductive or semi-conductive
31 ferromagnetic casing, or electrically non-conductive

1   or non-ferromagnetic casing. The casing string

2   typically comprises of a plurality of casing lengths

3   which are threadedly coupled together, thus making

4   joints (or collars) therebetween.

5

6   The tool 32 is lowered into the cased wellbore using

7   the slickline 12. The slickline 12 is typically

8   formed of a metal which has a high yield strength to

9   weight ratio and is capable of supporting the tool 32

10   (and any other tools which may form part of a

11   downhole tool string). It will be appreciated that

12   the slickline 12 should also be capable of

13   functioning as a monopole antenna.

14

15   The slickline 12 is preferably (but not essentially)

16   electrically insulated and/or isolated using a thin

17   outer coating of a flexible, non-conductive

18   insulating material. It is preferred that the

19   material should also be chemical, abrasion and

20   temperature resistant to endure the hazardous

21   downhole environments. The coating is typically an

22   enamel coating.

23

24   It should be noted that it may not be necessary to

25   provide an insulating coating on the slickline 12.

26   If a stuffing box or the like is used, the slickline

27   12 will be electrically isolated by the stuffing box.

28   However, this requires that the slickline 12 does not

29   come into contact with any part of the conductive

30   wellbore which may be difficult in deviated

31   (horizontal) wells or the like. It is thus preferred

1   that the slickline 12 is coated with an insulating

2   coating to ensure good electrical isolation. It

3   should be noted that coating the slickline 12 with an

4   enamel material also protects the metal wire (from

5   which the slickline 12 is made) against corrosion.

6   In addition, or alternatively, a corrosive chemical

7   sensitive material(s) may be applied as a coating or

8   part thereof on the slickline 12, and this would have

9   the advantage that the presence of corrosive

10   chemicals, such as H_2S or CO_2 or nitrates, in the

11   well would be indicated to the operator when the

12   slickline 12 is removed from the well since the

13   corrosive chemical sensitive material will be

14   transformed; for example, the colour of the corrosive

15   chemical sensitive material may change. In addition,

16   or alternatively, a stress/impact sensitive

17   material(s) may be applied as a coating or part

18   thereof on the slickline 12, and this would have the

19   advantage that mechanical damage to the slickline 12

20   in the well would be indicated to the operator when

21   the slickline 12 is removed from the well, since the

22   stress/impact sensitive material will be transferred;

23   for example, the colour of the impact/stress

24   sensitive material may change.

25

26   The enamel material may consist of one or more layers

27   of coating whereby each individual layer adds to the

28   overall required coating properties. Additionally,

29   each layer of enamel material preferably has the

30   required bonding, flexibility and stretch

31   characteristics at least equal to those of the metal

1   slickline 12 or coiled tubing. The thickness of the

2   enamel material can vary depending upon the downhole

3   conditions encountered, but is generally in the order

4   of 10 to 100 microns.

5

6   The enamel material can typically be applied to the

7   slickline 12 by firstly applying a thin layer of

8   adhesive, such as nylon or other suitable primer.

9   Thereafter, one or more layers of an enamel material

10 such as polyester, polyamide, polyamide-imide,

11 polycarbonates, polysulfones, polyester imides,

12 polyether, ether ketone, polyurethane, nylon, epoxy,

13 equilibrating resin, or alkyd resin or theic

14 polyester, or a combination thereof. The enamel

15 material is preferably polyamide-imide.

16

17 The conventional method of measuring downhole tool

18 depth is to run the slickline 12 against the sheave

19 wheel 22. It should be noted that use of "depth" in

20 this context is understood as being the trajectory

21 length of the downhole tool, which may be different

22 from conventional depth if the wellbore is deviated,

23 for example. In order to calculate the distance of

24 travel of the slickline 12, a number of variable

25 factors must be known. It is a prerequisite that the

26 rotational direction of the sheave wheel 22, the

27 number of revolutions thereof, the diameter of the

28 sheave wheel 22 and, depending upon the type of

29 sheave wheel 22 (that is, whether a point-type

30 contact or arc for example), the diameter of the

31 slickline 12, must all be known before the distance

1   of travel of the slickline 12 within the wellbore can

2   be calculated (and thus the depth of the tool).

3

4   However, with this conventional method for

5   calculating the distance of travel of the slickline

6   12, a number of factors render the calculation

7   inaccurate. The occurrence of wheel slippage, the

8   stretch of the slickline 12 (whether due to the

9   weight of the slickline 12 itself, or the weight of

10   the tool string to which it is attached), the effect

11   of friction and the well-contained fluid buoyancy all

12   contribute to decrease the accuracy of the

13   conventional tool depth measurement.

14

15   In order to improve the accuracy of this conventional

16   depth measurement, it is known to combine the

17   measured tensile load, the known stretch co-efficient

18   of the slickline 12, and the conventionally measured

19   tool depth as described above, to recalculate the

20   tool depth measurement on a continuous (ie real time)

21   basis using a processing means (eg a computer).

22

23   However, the accuracy of the aforementioned depth

24   measurement correction method relies on an

25   experimentally determined constant (ie the stretch

26   co-efficient of the slickline 12) and the surface

27   measurements of the weight of the slickline 12. The

28   resulting correction does not include the significant

29   combined effect that well fluid temperature, tool

30   buoyancy and well geometry have on the accuracy of

31   the depth correction.

1 When the tool 32 detects a casing collar or joint
2 during normal slickline operations at downhole tool
3 travelling speed, the tool 32 will process the
4 collected data at normal wireline operational speed
5 using a processing device and signal generator 71
6 (Fig. 4) which forms part of the transmitter 46. The
7 processing device and signal generator 71
8 communicates a signal (via a SAW oscillator 73 and
9 418 MHz band-pass filter 75) indicative of the
10 location of the collar or joint to the slickline 12
11 which acts as an antenna. At the surface, this
12 signal is received by the surface receiver 80 (Fig.
13 5). The receiver 80 is coupled to the processing
14 means (eg a computer) located at the surface and the
15 signal from the tool 32 is used to calibrate the
16 conventional measured depth against the known
17 distance between the preceding collar or joint, or
18 other known location. This distance is typically
19 known from an existing record log of the individual
20 casing lengths.
21
22
23 A number of arrays of magnetic field sensors 58
24 positioned on axially spaced-apart horizontal planes
25 within the tool 32 (as shown in Fig. 1) can be used,
26 each of the sensor arrays having their own channel as
27 described above and being set at known (but not
28 necessarily equal) distances along the longitudinal
29 axis of the tool 32. This allows for increased
30 accuracy of the calibration due to the repeated
31 calibration against the detected collar or joint. It

1   should be noted that when using multiple arrays of

2   sensors 58, only a single transmitter 46 and receiver

3   80 need be used as each array 58 will have their own

4   individual channel which can be selected or

5   deselected as required.

6

7   However, if the communication system is being used

8   with other sensors within the tool, these other

9   sensors may be coupled to another transmitter and

10 receiver, the other transmitter and receiver

11 including a different address coding. This allows

12 multiple transmissions to multiple receivers 80 from

13 multiple transmitters 46 using only one slickline 12

14 as the antenna.

15

16 The signal from the tool 32 is, for the purpose of

17 the described tool depth measurement calibration, a

18 measure of a known trajectory length of the tool 32

19 in relation to a detected collar or casing joint end

20 length (casing-section length calibration). This is

21 dependent upon the configuration of tool 32 within

22 the downhole tool or string. Alternatively, the

23 signal is a measure of the trajectory length as

24 travelled by the tool 32 in relation to the detected

25 collar or casing joint as indicated by each separate

26 positive signal from the tool 32 (downhole tool

27 length calibration). For the casing section length

28 calibration technique, the accuracy of the

29 calibration may depend upon the accuracy and

30 completeness of surveyed well details, that is the

31 length of the individual casing sections and the

1   configuration thereof. For the downhole tool length

2   calibration method, surveyed well details are not

3   necessary.

4

5   With the casing length calibration method

6   (hereinafter CLC), the trajectory length or tool

7   depth calibration, as performed by the processing

8   means at the surface, uses the received signal from

9   the tool 32 and references this signal against the

10   conventionally obtained surface measured depth,

11   obtained as described above, and the details of the

12   well. That is, the individual casing length is used

13   to calculate a depth correction factor μ wherein

14

$$\mu_{CLC} = L_c/(D_2 - D_1),$$

15

16

17   wherein

18

19   L_c = casing length;

20   D_1 = surface depth at the previous casing collar or

21   joint;

22   D_2 = surface depth at the detected casing collar or

23   joint, where $D_2 > D_1$; and

24   μ_{CLC} = depth correction factor.

25

26   The depth correction factor μ_{CLC} is used by the

27   processing means to correct the conventionally

28   obtained depth over the next downhole tool trajectory

29   casing length.

30

1   With the downhole tool length calibration method

2   (hereinafter TLC), the trajectory length or tool

3   depth calibration is performed by the processing

4   means located at the surface, for example. The

5   processing means uses the received signal from the

6   tool 32 and references this signal against the

7   conventionally obtained surface measured depth to

8   calculate a depth correction factor μ. The

9   correction factor μ can be calculated as follows for

10   equidistant sensor spacing (ie constant distance

11   between sensors)

12

13                    $$\mu_{TLC} = L_u/(D_n - D_{n-1}),$$

14

15   wherein

16

17   L_u = tool sensor distance constant (ie the uniform

18   distance between the sensors);

19   D_1 = surface depth at the first tool sensor;

20   D_{n-1} = surface depth at the previous casing collar or

21   joint;

22   D_n = surface depth at the detected casing collar or

23   joint, where $D_n > D_{n-1} > D_1$; and

24   μ_{TLC} = depth correction factor.

25

26   The correction factor μ can be calculated as follows

27   for non-uniform sensor spacing (ie non-constant

28   distance between sensors)

29

30                    $$\mu_{TLC} = L_n/(D_n - D_{n-1}),$$

1

2   wherein

3

4   L_n = tool sensor distance spacing (ie the non-uniform

5   distant between the sensors);

6   D_1 = surface depth at the first tool sensor;

7   D_{n-1} = surface depth at the previous casing collar or

8   joint;

9   D_n = surface depth at the detected casing collar or

10   joint, where $D_n > D_{n-1} > D_1$; and

11   μ_{TLC} = depth correction factor.

12

13   The depth correction factor μ_{TLC} thus derived can be

14   used by the processing means to correct the

15   conventionally obtained depth over the next travelled

16   spacing between the sensors (either uniform or non-

17   uniform). If the total tool distance (that is the

18   distance between the sensors provided in the tool 32)

19   is less than the individual casing length, the

20   derived multiple-calibrated correction factor μ_{TLC} may

21   be used to correct the conventionally obtained depth

22   related input over the next downhole tool trajectory

23   individual casing length.

24

25   It will be appreciated that the depth correction

26   described above need not be performed in real-time.

27   A running history file can be constructed using each

28   surface-received signal from the tool 32 and after

29   completion of a slickline run (downhole tool travel

30   from surface to a depth and return to surface), the

31   history file can be compared against a similar file

1   derived from the conventional depth measurement

2   technique and the results analysed to interpret and

3   evaluate the downhole tool run objectives and

4   results.

5

6   It will be appreciated that the use of a slickline as

7   an antenna is not limited to facilitate an increase

8   in accuracy of tool depth measurements. For example,

9   the conventional method for detecting the status of a

10   downhole tool or tools (that is a tool which is

11   deigned to perform downhole functions such as setting

12   plugs or isolating sections of the wellbore to deploy

13   memory gauges) would be by a differential calculation

14   involving the experience of the slickline operator in

15   conjunction with correlated depth between distance

16   travelled by the slickline (calculated using the

17   conventional technique) and the location of a

18   "nipple" in conjunction with the previously recorded

19   "nipple" depth or tubing tally, or by other means

20   involving physical stresses in the slickline (for

21   example increased/decreased tension in the

22   slickline). A "nipple" is a receptacle in which the

23   downhole tool locates and latches into, or the

24   position in the tubing or casing string for the

25   deployment of the downhole tool to carry out its

26   function.

27

28   Once the downhole tool has been deployed or

29   retrieved, the slickline winch operator typically

30   sees a corresponding decrease or increase in the

31   weight of the tool string equivalent to the weight of

1 the tool, which would be indicative of a successful

2 deployment or retrieval.

3

4 However, where the downhole tool is of a marginal

5 weight so as not to show a significant difference in

6 the weight of the tool string once it has been

7 deployed or retrieved, or when circumstances inside

8 the wellbore give a smaller indication than one of

9 those described above (for example an obstruction in

10 the tubing or such like), the status of the downhole

11 tool is derived by conjecture until a time when the

12 function of the tool can be operatively tested or the

13 tool string is returned to the surface.

14

15 As will be appreciated, these methods of ascertaining

16 the status of downhole tools are not accurate and

17 rely on the experience of the slickline winch

18 operator, a careful tally of running and pulling

19 weights, and accurate weight indication and depth

20 correlation means. Even when these criteria have all

21 been met, there is no guarantee that the downhole

22 tool has been successfully deployed or retrieved

23 correctly and where downhole tools which rely on the

24 position of sliding sleeves are used, there is no

25 indication of the position thereof until further

26 tests have been carried out.

27

28 The present invention facilitates a means to actively

29 identify when a downhole tool has been deployed or

30 retrieved etc by incorporating into the previously

31 described apparatus one or more sensors (eg a

1   proximity or electrically connecting/disconnecting
2   sensor) which activates the transmission of a signal
3   via the slickline antenna which is indicative of the
4   status of the tool (ie latched, unlatched, engaged,
5   disengaged etc). This would provide a more reliable
6   indication of the tool status in connection with the
7   previously described depth correlation which
8   substantially mitigates the possibility of human
9   error in identifying whether the downhole tool has
10 been correctly deployed or retrieved etc.
11
12 When a downhole tool has been deployed, retrieved or
13 otherwise, it is normally the case to use a
14 mechanical force in order to facilitate this
15 deployment, retrieval or otherwise in order to
16 operate a mechanism incorporated in the downhole tool
17 in order to carry out the function of the tool. An
18 example of this would be a running tool which is used
19 to deploy a downhole plug which typically relies on
20 the slickline operator to locate the tool in its
21 downhole position using the conventional depth
22 measurement. Thereafter, either pulling sharply on
23 the slickline or rapidly slackening it induces a
24 hammering effect on the tool whereby a pin (or a
25 plurality thereof) are sheared to allow the tool to
26 engage in a locking assembly, thus disconnecting the
27 tool from the string, or a collar is pulled to
28 retract such an assembly in order to release the tool
29 from the locking assembly thus connecting the tool to
30 the string.
31

1   A signal from a proximity sensor or the like can be
2   propagated to the surface using the slickline as an
3   antenna, the signal being received at the surface and
4   causing, for example, a second signal to be
5   transmitted from the surface to a relay provided on
6   the (downhole) tool to electrically or
7   electromechanically operate an automatic locking or
8   unlocking device. This would eliminate the
9   requirement for mechanical hammering to initiate the
10   functioning of the downhole tool.

11
12   Another application of the present invention would be
13   during the deployment of downhole tools, a part or
14   parts of the tool itself or the tool string can
15   loosen or be disconnected from the tool or string.
16   This can then require several runs into the wellbore
17   in order to recover the tool or part thereof. This
18   can be a very expensive process.

19
20   To overcome this, the tools within the tool string or
21   the parts of the tool themselves can be coupled
22   together either electrically or magnetically wherein
23   discontinuity of the electrical or magnetic
24   connection triggers a signal or a plurality of
25   signals which can be transmitted to the surface to
26   indicate to the slickline operator that such an event
27   is about to occur.

28
29   Modifications and improvements may be made to the
30   foregoing without departing from the scope of the
31   present invention. For example, the foregoing

1 description relates to the use of a slickline as an
2 antenna, but it will be appreciated that it is
3 equally possible to use a braided line or a mono-
4 conducting slickline. Additionally, the pulsed
5 transmission to the surface could be replaced by a
6 continuous type transmission, or alternatively, may
7 be a pulsed or continuous two-way communication
8 between the surface and a tool, using suitable
9 transmitters and receivers (or transceivers) for such
10 communications.
11
12 Although the foregoing description relates to the use
13 of a tool which detects the location and passage of
14 collars in a cased wellbore, it will be appreciated
15 that tools exist which are sensitive to non-collared
16 pipe joints.
17
18 Additionally, it will be appreciated that the
19 communication system described herein enables the use
20 of a slickline in combination with downhole tools,
21 such as flow meters, pressure, temperature,
22 gravitational, sonic and seismic sensors, downhole
23 cameras and/or optic/IR sensors which have hitherto
24 relied on electric (single- or multi-conductor)
25 braided slicklines for operation.
26
27

1   CLAIMS:-

2

3   1.   A communication system for use in a wellbore,

4   the system comprising a transmitter coupled to a

5   wireline, and a receiver located remotely from the

6   transmitter, wherein the wireline is capable of

7   acting as an antenna for the transmitter.

8

9   2.   An apparatus according to claim 1, wherein the

10   wireline is a slickline.

11

12   3.   An apparatus according to either of claims 1 or

13   2, wherein the transmitter is associated with,

14   provided on, or an integral part of a downhole tool

15   or tool string.

16

17   4.   An apparatus according to claim 3, wherein the

18   downhole tool or tool string is suspended by the

19   wireline.

20

21   5.   An apparatus according to either of claims 3 or

22   4, wherein the transmitter transmits data collected

23   or generated by the downhole tool or the like to the

24   receiver.

25

26   6.   An apparatus according to any preceding claim,

27   wherein the receiver is located at, or near, the

28   surface of the wellbore.

29

30   7.   An apparatus according to any preceding claim,

31   wherein the transmitter is coupled to the wireline at

1   or near a downhole tool whereby the distance

2   travelled by the tool, the status of the tool or

3   other parameters of the tool, can be transmitted to

4   the receiver.

5

6   8.   Apparatus according to any preceding claim,

7   wherein the wireline is electrically insulated.

8

9   9.   Apparatus according to any preceding claim,

10   wherein the wireline is sheathed to facilitate

11   electrical insulation.

12

13   10.   A method of communication in a wellbore,

14   comprising providing a transmitter coupled to a

15   wireline, paying an end of the wireline and the

16   transmitter into the wellbore, and providing a

17   receiver located remotely from the transmitter, such

18   that the wireline acts as an antenna for the

19   transmitter.

20

21   11.   A wireline for use in a wellbore, wherein the

22   wireline is provided with an insulating coating.

23

24   12.   A wireline according to claim 11, wherein the

25   insulating coating is an outer coating of the

26   wireline.

27

28   13.   A wireline according to either of claims 11 or

29   12, wherein the wireline comprises a slickline.

30

14. A wireline according to any of claims 11 to 13, wherein the insulating coating comprises at least one enamel material.

15. A distance measurement apparatus for measuring the distance travelled by a wireline, the apparatus comprising at least one sensor coupled to the wireline wherein the sensor is capable of sensing known locations in a wellbore.

16. Apparatus according to claim 15, wherein the wireline is typically a slickline.

17. Apparatus according to either of claims 15 or 16, wherein the apparatus includes transmission means for transmitting data collected by the at least one sensor to a receiver located remotely from the apparatus.

18. Apparatus according to claim 17, wherein the wireline is capable of acting as an antenna for the transmission means.

19. Apparatus according to either of claims 17 or 18, wherein the sensor is coupled at or near a downhole tool whereby the distance travelled by the tool, and the location of the tool within the wellbore, can be calculated.

20. Apparatus according to any of claims 17 to 19, wherein the wireline is electrically insulated.

1   21. A method of measuring the distance travelled by

2   a wireline, the method comprising the steps of

3   coupling at least one sensor to the wireline, the at

4   least one sensor being capable of sensing known

5   locations in a wellbore; running the wireline into

6   the wellbore; calculating the depth of the at least

7   one sensor; generating a signal when the at least one

8   sensor passes said known locations; using the signal

9   to calculate a depth correction factor; and

10   correcting the calculated depth using the depth

11   correction factor.

12

13   22. A downhole tool comprising coupling means to

14   allow the tool to be attached to a wireline, at least

15   one sensor capable of detecting known locations in a

16   wellbore and generating a signal indicative thereof,

17   and a transmission means capable of transmitting the

18   signal.

19

20   23. A downhole tool according to claim 20, wherein

21   the wireline acts as an antenna for the transmission

22   means.

23

24   24. A downhole tool according to either of claims 22

25   or 23, wherein the coupling means comprises a rope-

26   socket.

27

28   25. A downhole tool according to claim 24, wherein

29   the rope-socket is provided with signal coupling

30   means to couple the signal generated by the

31   transmission means to the wireline.

26. A downhole tool according to any of claims 20 to 23, wherein the downhole tool is powered by a DC power supply.

27. A method of tracking a member in a wellbore, the method comprising providing a sensor on the member, inserting the member and sensor into the wellbore, obtaining information indicating the position of the sensor in the wellbore, and determining the distance travelled by said member from said sensor information.

28. Apparatus for indicating the configuration of a downhole tool or tool string, the apparatus comprising at least one sensor capable of sensing a change in the configuration of the downhole tool or tool string and generating a signal indicative thereof, and a transmission means electrically coupled to the at least one sensor for transmitting the signal to a receiver.

29. Apparatus according to claim 28, wherein the downhole tool is preferably suspended in a borehole using a wireline, and the wireline is capable of acting as an antenna for the transmission means.

30. Apparatus according to either of claims 28 or 29, wherein the transmitter facilitates the transmission of data collected by the sensor to the receiver.

1   31.   Apparatus according to any of claims 28 to 30,
2   wherein the transmission means comprises a
3   transmitter.
4
5   32.   Apparatus according to any of claims 28 to 31,
6   wherein the receiver is located at, or near, the
7   surface of the borehole.
8
9   33.   Apparatus according to any of claims 26 to 30,
10 wherein the apparatus is arranged whereby it can
11 facilitate two-way communication between the downhole
12 tool and the receiver.
13
14 34.   Apparatus according to any of claims 28 to 32,
15 wherein the sensor comprises an electric or magnetic
16 sensor which is coupled to the downhole tool wherein
17 a discontinuity of the respective electric or
18 magnetic connection triggers at least one signal.
19
20 35.   Apparatus according to any of claims 29 to 34,
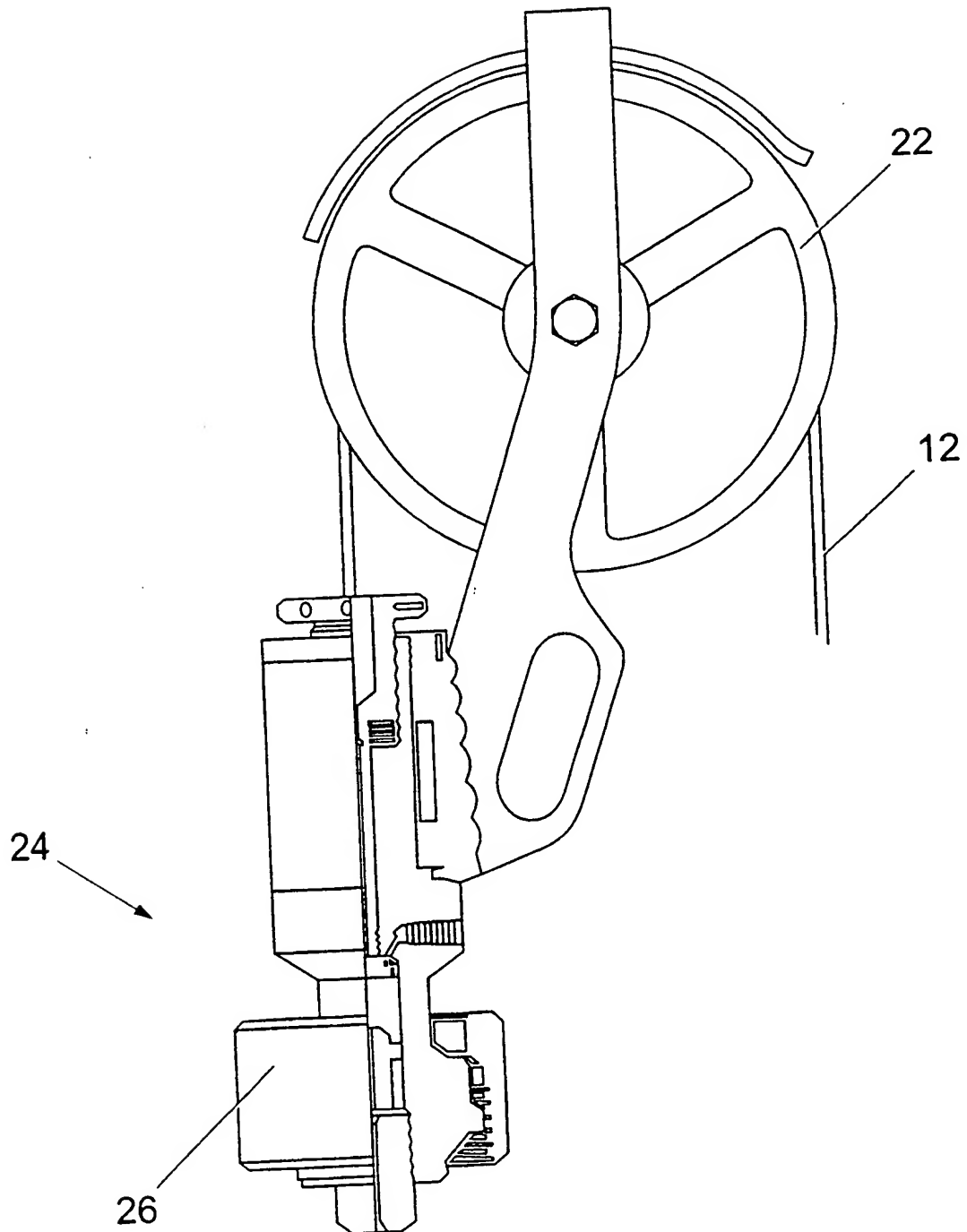21 wherein the wireline is electrically insulated.
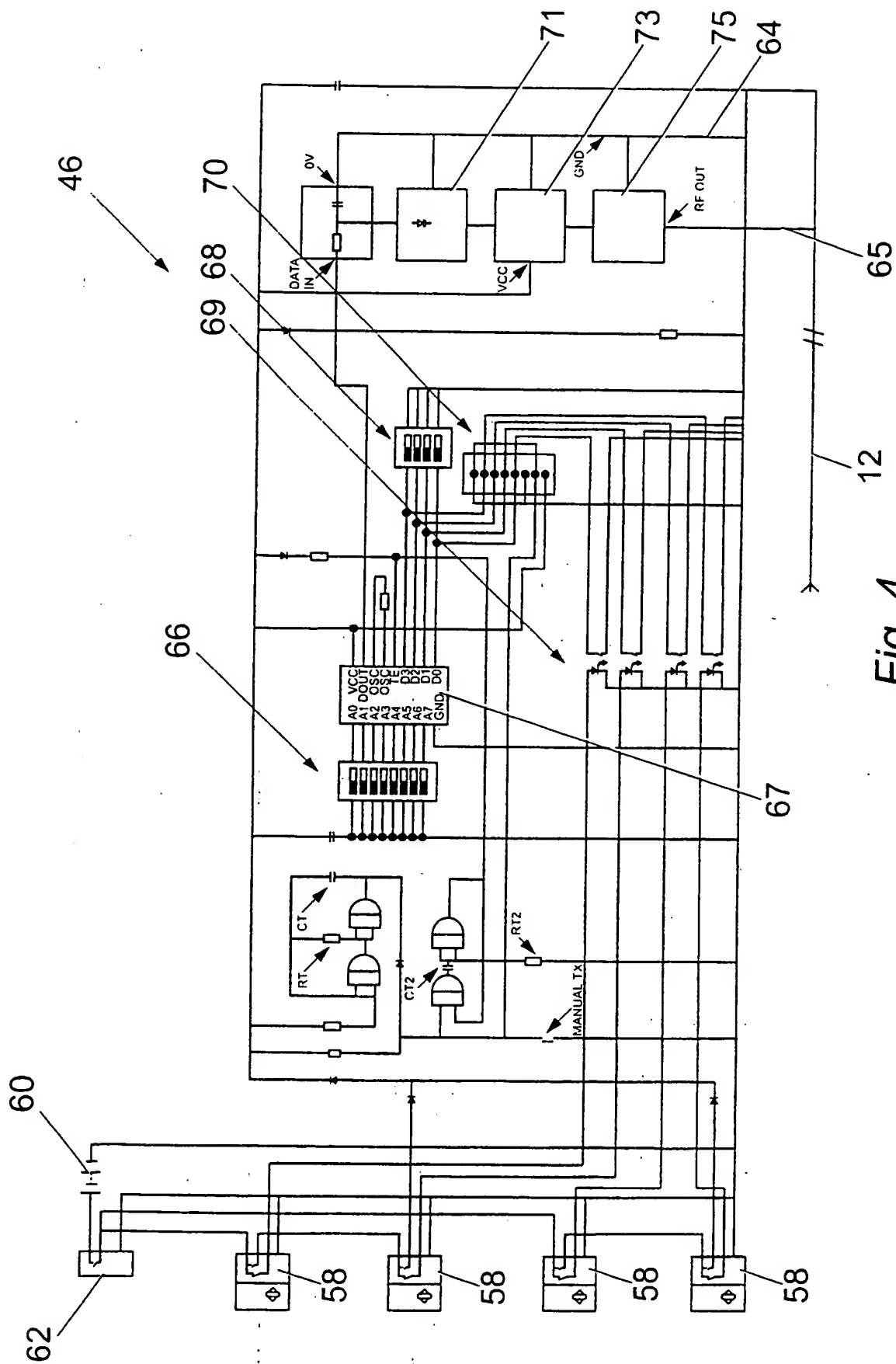22
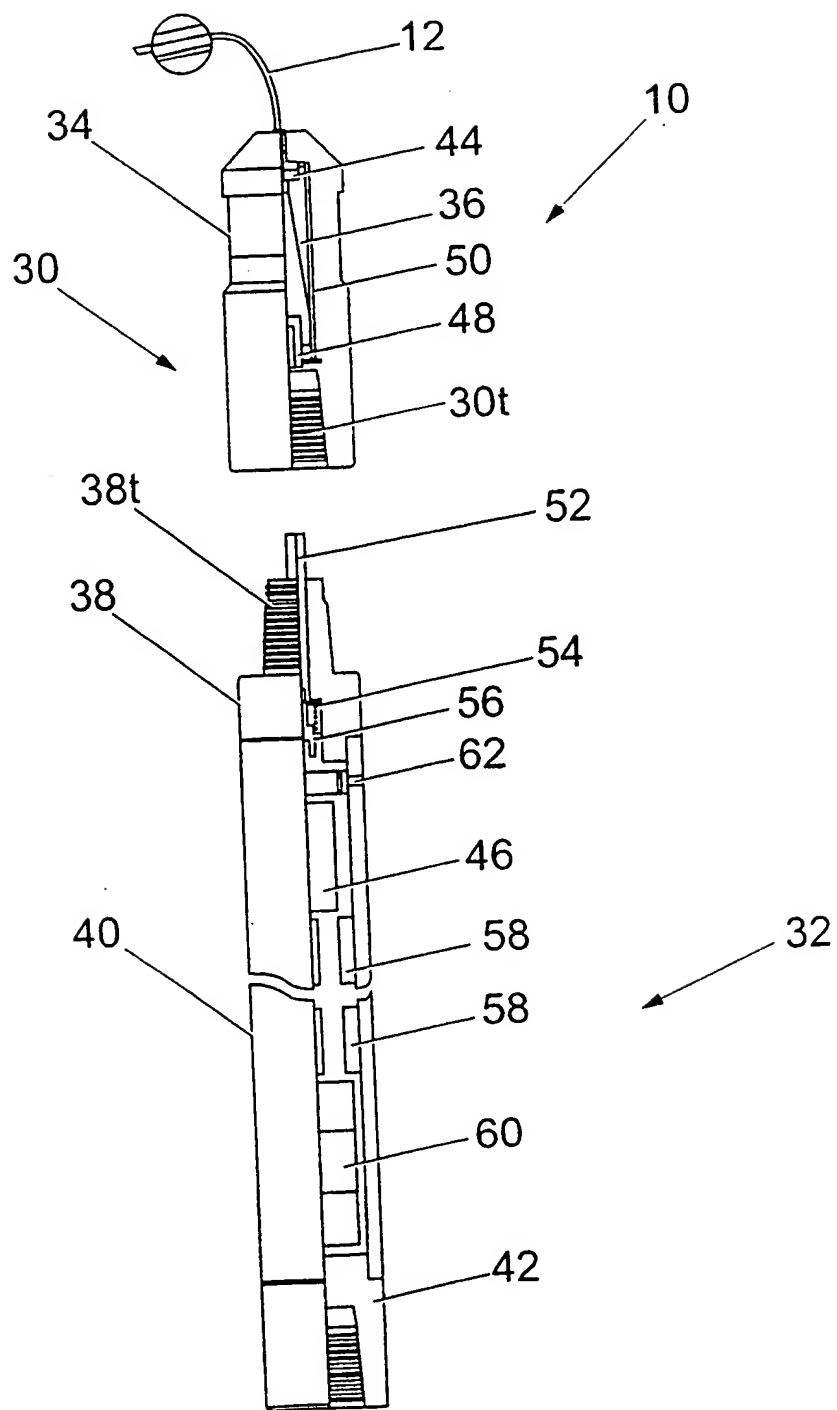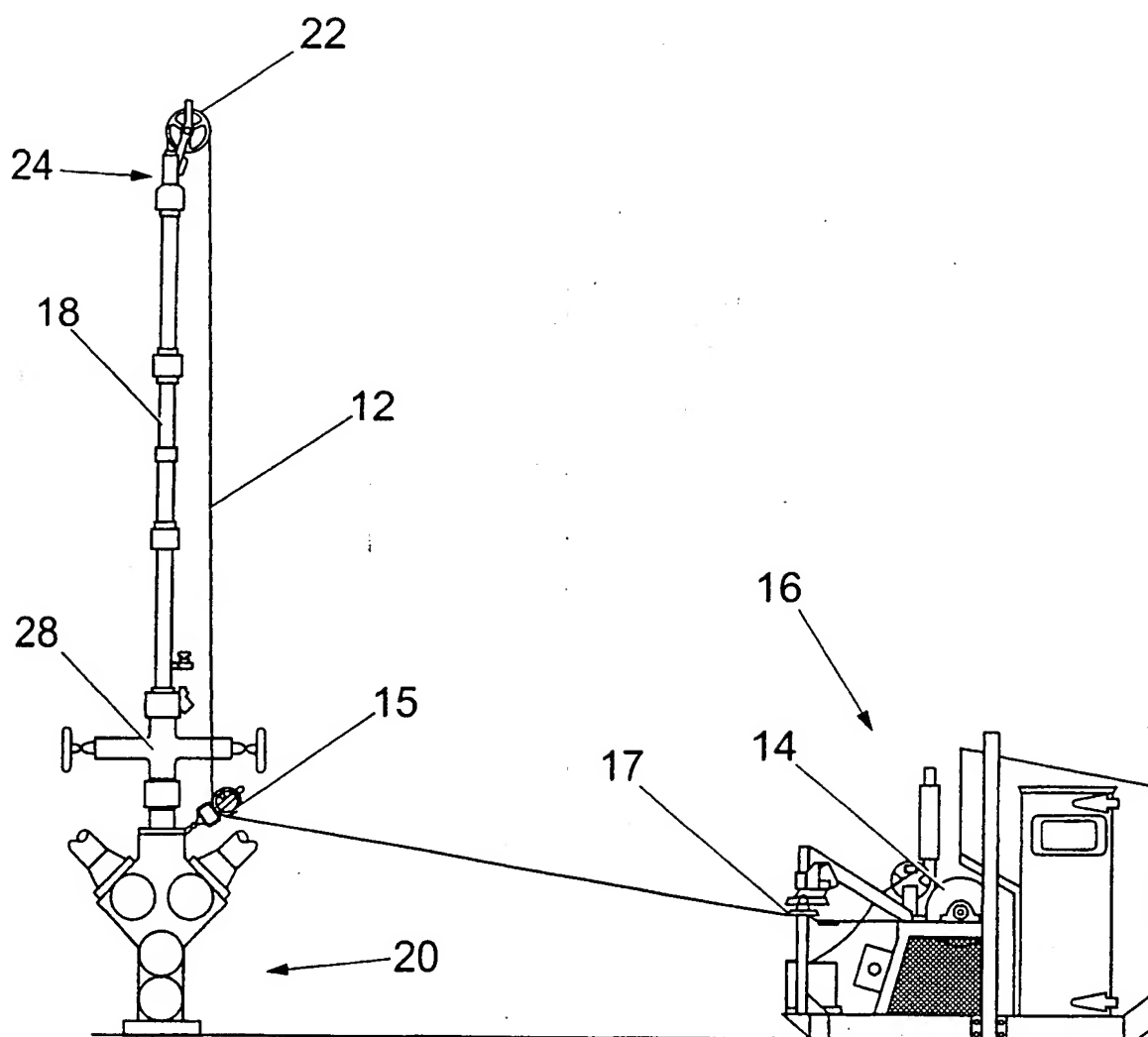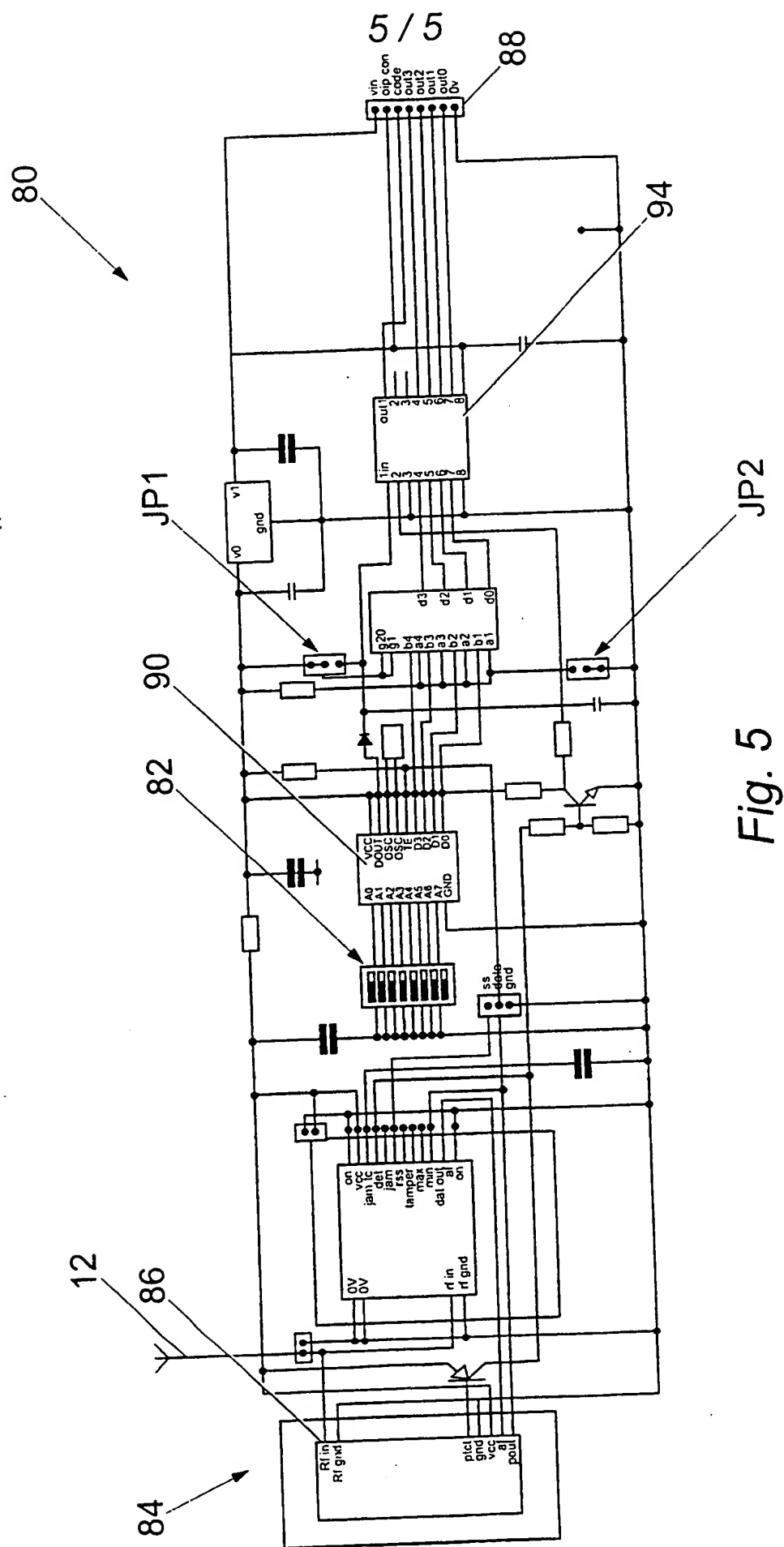
Fig. 1

Fig. 2

Fig. 3

4 / 5

Fig. 4

5 / 5

Fig. 5

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(81) Designated States *(national):* AE, AL, AM, AT, AU, AZ, BA, BB, BG, BR, BY, CA, CH, CN, CR, CU, CZ, DE, DK, DM, EE, ES, FI, GB, GD, GE, GH, GM, HR, HU, ID, IL, IN, IS, JP, KE, KG, KP, KR, KZ, LC, LK, LR, LS, LT, LU, LV, MA, MD, MG, MK, MN, MW, MX, NO, NZ, PL, PT, RO, RU, SD, SE, SG, SI, SK, SL, TJ, TM, TR, TT, TZ, UA, UG, US, UZ, VN, YU, ZA, ZW.

(54) Title: APPARATUS AND METHODS FOR MEASURING DEPTH

(57) Abstract: A communication system for use in a wellbore, a downhole tool, and a method includes a transmitter coupled to a wireline, and a receiver located remotely from the transmitter. The wireline is capable of acting as an antenna for the transmitter. The wireline is a slickline, and the transmitter may be associated with, provided on, or an integral part of a downhole tool or tool string. The transmitter typically transmits data collected or generated by the downhole tool or the like to the receiver, which is preferably located at, or near, the surface of the wellbore. The wireline is typically provided with an insulating coating. Also, a distance measurement apparatus and a method for measuring the distance travelled by a wireline includes at least one sensor coupled to the wireline, and the sensor is capable of sensing known locations in a wellbore.

(84) **Designated States** *(regional)*: ARIPO patent (GH, GM, KE, LS, MW, MZ, SD, SL, SZ, TZ, UG, ZW), Eurasian patent (AM, AZ, BY, KG, KZ, MD, RU, TJ, TM), European patent (AT, BE, CH, CY, DE, DK, ES, FI, FR, GB, GR, IE, IT, LU, MC, NL, PT, SE), OAPI patent (BF, BJ, CF, CG, CI, CM, GA, GN, GW, ML, MR, NE, SN, TD, TG).

Published:
— *with international search report*

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2 August 2001

For two-letter codes and other abbreviations, refer to the "Guidance Notes on Codes and Abbreviations" appearing at the beginning of each regular issue of the PCT Gazette.

A. CLASSIFICATION OF SUBJECT MATTER

IPC 7   E21B47/12   E21B47/04

According to International Patent Classification (IPC) or to both national classification and IPC

B. FIELDS SEARCHED

Minimum documentation searched (classification system followed by classification symbols)

IPC 7   E21B

Documentation searched other than minimum documentation to the extent that such documents are included in the fields searched

Electronic data base consulted during the international search (name of data base and, where practical, search terms used)

EPO-Internal

C. DOCUMENTS CONSIDERED TO BE RELEVANT

Category°	Citation of document, with indication, where appropriate, of the relevant passages	Relevant to claim No.
X	US 4 001 774 A (DAWSON ET AL.) 4 January 1977 (1977-01-04) column 3, line 30 - line 64 column 4, line 19 - line 34	1-13
Y		14,18, 20,23, 29,35

Y	US 4 814 548 A (TRAVERSINO ET AL.) 21 March 1989 (1989-03-21) column 1, line 44 - line 46	14

A	US 3 209 323 A (GROSSMAN) 28 September 1965 (1965-09-28) column 5, line 18 - line 37	1

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[X] Further documents are listed in the continuation of box C.

[X] Patent family members are listed in annex.

° Special categories of cited documents :

"A" document defining the general state of the art which is not considered to be of particular relevance

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"O" document referring to an oral disclosure, use, exhibition or other means

"P" document published prior to the international filing date but later than the priority date claimed

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"X" document of particular relevance; the claimed invention cannot be considered novel or cannot be considered to involve an inventive step when the document is taken alone

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"&" document member of the same patent family

Date of the actual completion of the international search	Date of mailing of the international search report
28 February 2001	0 6. 03. 2001

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C.(Continuation) DOCUMENTS CONSIDERED TO BE RELEVANT

Category °	Citation of document, with indication, where appropriate, of the relevant passages	Relevant to claim No.
X	GB 936 461 A (TROSZT) 11 September 1963 (1963-09-11) page 3, line 27 - line 39 page 3, line 79 - line 91 page 4, line 49 - line 57 claim 1	15-17, 19,22, 24,25, 27,28, 30,32-34
Y		14,18, 20,23, 29,35

X	US 3 267 365 A (BAKER) 16 August 1966 (1966-08-16) column 1, line 29 - line 35 column 4, line 34 -column 5, line 39	15-17, 19,22, 24,25, 27,28, 30,32,34

X	US 3 185 997 A (CARLTON ET AL.) 25 May 1965 (1965-05-25) column 1, line 40 - line 42 column 2, line 32 - line 43 column 2, line 63 -column 3, line 42	15,16, 21,22, 26-28,34

X	US 4 044 470 A (DUFRENE) 30 August 1977 (1977-08-30) column 4, line 35 - line 68	22,24

INTERNATIONAL SEARCH REPORT

Box I   Observations where certain claims were found unsearchable (Continuation of item 1 of first sheet)

This International Search Report has not been established in respect of certain claims under Article 17(2)(a) for the following reasons:

1. ☐ Claims Nos.:
because they relate to subject matter not required to be searched by this Authority, namely:

2. ☐ Claims Nos.:
because they relate to parts of the International Application that do not comply with the prescribed requirements to such an extent that no meaningful International Search can be carried out, specifically:

3. ☐ Claims Nos.:
because they are dependent claims and are not drafted in accordance with the second and third sentences of Rule 6.4(a).

Box II   Observations where unity of invention is lacking (Continuation of item 2 of first sheet)

This International Searching Authority found multiple inventions in this international application, as follows:

    see additional sheet

1. ☒ As all required additional search fees were timely paid by the applicant, this International Search Report covers all searchable claims.

2. ☐ As all searchable claims could be searched without effort justifying an additional fee, this Authority did not invite payment of any additional fee.

3. ☐ As only some of the required additional search fees were timely paid by the applicant, this International Search Report covers only those claims for which fees were paid, specifically claims Nos.:

4. ☐ No required additional search fees were timely paid by the applicant. Consequently, this International Search Report is restricted to the invention first mentioned in the claims; it is covered by claims Nos.:

Remark on Protest   ☐ The additional search fees were accompanied by the applicant's protest.

                              ☒ No protest accompanied the payment of additional search fees.

FURTHER INFORMATION CONTINUED FROM   PCT/ISA/ 210

This International Searching Authority found multiple (groups of) inventions in this international application, as follows:

1. Claims: 1-14

   Communication system

2. Claims: 15-35

   Downhole depth measurement system

Patent document cited in search report		Publication date	Patent family member(s)	Publication date
US 4001774	A	04-01-1977	NONE	
US 4814548	A	21-03-1989	NONE	
US 3209323	A	28-09-1965	NONE	
GB 936461	A		NONE	
US 3267365	A	16-08-1966	NONE	
US 3185997	A	25-05-1965	NONE	
US 4044470	A	30-08-1977	NONE	